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Test and Evaluation of Non Conventional Instrument Transformers and Sampled Value Process Bus on Powerlink's Transmission Network

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1 Abstract

IEC 61850 Process Bus technology has the potential to improve cost, performance and reliability of substation design. Substantial costs associated with copper wiring (designing, documentation, construction, commissioning and troubleshooting) can be reduced with the application of digital Process Bus technology, especially those based upon international standards. An IEC 61850-9-2 based sampled value Process Bus is an enabling technology for the application of Non-Conventional Instrument Transformers (NCIT). Retaining the output of the NCIT in its native digital form, rather than conversion to an analogue output, allows for improved transient performance, dynamic range, safety, reliability and reduced cost.

In this paper we report on a pilot installation using NCITs communicating across a switched Ethernet network using the UCAIug Implementation Guideline for IEC 61850-9-2 (9-2 Light Edition or 9-2LE). This system was commissioned in a 275 kV Line Reactor bay at Powerlink Queensland's Braemar substation in 2009, with sampled value protection IEDs 'shadowing' the existing protection system. The results of commissioning tests and twelve months of service experience using a Fibre Optic Current Transformer (FOCT) from Smart Digital Optics (SDO) are presented, including the response of the system to fault conditions.

A number of remaining issues to be resolved to enable wide-scale deployment of NCITs and IEC 61850-9-2 Process Bus technology are also discussed.

2 Introduction

For many years power utilities and manufacturers have been in search of reliable NCITs to measure current and voltage in order to simplify and compact the primary equipment; reduce their environmental footprint; increase the flexibility of the systems; reduce the occurrence of problems and safety hazards associated with conventional Instrument Transformer (IT) technology. While NCITs have been used in medium voltage installations for many years, the absence of a digital interface standard has slowed the introduction NCITs into the High Voltage (HV) transmission domain. One of the new international standards IEC 61850-9-2, first released in 2004, is providing a digital interface standard for connection of NCITs to revenue meters, protection and control equipment, thus providing equipment manufacturers and system integrators a sound basis for the development of NCIT and Substation Automation System (SAS) product and multivendor solutions.

Powerlink's technology strategy is to move towards an IEC 61850 Process Bus [10] solution in a two-step approach. The first step encompasses the development and transition to a new design based on IEC 61850 Station Bus [1] by 2012. The second step includes the adoption of IEC 61850 Process Bus features such as NCITs and switchgear with electronic interfaces. The optimum timing for the transition to a Process Bus solution is dependent on continued development of relevant international standards and the availability of equipment compliant to those standards. The implementation of pilot projects such as the one outlined in this paper enables Powerlink to investigate market maturity of Process Bus equipment, their application and to further refine Powerlink's IEC 61850 technology roadmap.

2.1 History and Benefits of NCITs

NCITs have been in existence for almost 100 years, with Rogowski first describing the air-cored current transformer, now called a 'Rogowski Coil' [2]. This device has been adopted in power systems due to its compact size, frequency response and linearity [3]. Most power industry applications of Rogowski coils have been for indoor Gas Insulated Switchgear (GIS) where space is at a premium. ABB adopted this technology for their multifunction hybrid switchgear, called 'Plug and Switch System' (PASS), as the current sensor could be combined with a voltage sensor and engineered into the switchgear.

Measurement of current in EHV power systems with an optical CT using the Faraday Effect was first demonstrated by Saito in 1966 [4]. An optical CT using a Sagnac interferometer that overcame the need for exceptionally stable optical components and was insensitive to vibration, was presented in 1996 [5]. The first three phase trial took place at BC Hydro's Ingledow substation (Surrey, British Columbia, Canada) in 2000 [6]. This trial used optical voltage sensors, which are a more recent development, with a sensor using three Pockels cells developed in 2000 [7]. Most NCIT trials have used capacitive voltage sensors rather than optical voltage sensors [8], especially in conjunction with Rogowski coil current sensors.

Optical CT systems based on the Faraday Effect, such as the one used in Powerlink's pilot project, have significant benefits relative to other technologies including: -

- *Dynamic Range:* The magnetising current in conventional CTs limits the lowest currents which can be measured. Optical sensors do not have this limitation and remain accurate down to zero current. Similarly, optical sensors do not suffer from the saturation effects of conventional CTs and remain linear to extremely large currents.
- *Bandwidth:* The bandwidth of optical sensors is theoretically limited by the propagation time of the light in the optical fibre coil which is sensing the current. Practically, this limit is very high - the actual limit is more likely to be anti-aliasing filters in the process of digitizing the optical signals.
- *Safety:* The optical output of the optical sensor poses no safety risk, unlike the potentially lethal voltages available from conventional CTs.
- *Environmental:* Optical CTs do not require oil or SF_6 insulation, and so present a much lower risk to the environment.
- *Reliability:* With no complex, highly stressed insulation systems and only passive optical components at high potential, the reliability of optical fibre sensors is excellent. Additionally, because of the large amount of information which is continuously acquired from the sensor, the health of the system can be constantly monitored and the accuracy of the data assured.
- *Size:* The small size and weight of the optical sensors reduces the requirements for mechanical support which results in increased flexibility in mounting of the devices, e.g. mounting on existing post insulators or supported by a rigid bus. The small mass of the sensors also results in greater immunity to seismic events.

- *Digital:* The data acquisition and processing in the optical sensor is inherently digital, allowing for the transmission in digital formats, such as IEC 61850-9-2, without any loss in accuracy, resolution or dynamic range.
- *Cost:* Relative to conventional CTs, optical sensors can provide significant cost reductions through reduced installation, maintenance and disposal costs, spares inventory, copper and structural requirements.

The first digital interface standard for electronic current transformers was defined in IEC 60044-8 [9], which was released in 1998. This was first used experimentally by RTE and Alstom at the Vielmoulin 400 kV substation in France. IEC Technical Committee 38 (Instrument Transformers), commonly referred to as IEC TC38, are working on a series of standards, including IEC 61869-9 for digital interfaces to electronic instrument transformers. This standard is based upon the UCA 9-2LE Guideline [11], commonly termed '9-2 Light Edition' or '9-2LE', additional features and is forecast for release in December 2012.

2.2 9-2LE Sample Value Process Bus

The IEC 61850 standards are based around the same Ethernet that is used for conventional office and commercial networking. IEC 61850-9-2 [10] specifies a standard communications mapping for Sampled Values (SV).

SV requires the use of VLAN frame tagging according to IEEE Std 802.1Q-2005, which is commonly referred to as '802.1Q tagging'. 802.1Q tags provide additional information to network switches about which virtual network a frame belongs (the VLAN ID, or VID) and the Class of Service (CoS) that VLAN aware switches should assign to the frame (the priority). VLAN segregation is optional, and so 'priority only' tags, indicated by a VID of 0, are required if VLANs are not used.

In an attempt to reduce the complexity and variability of implementing SV complying with IEC 61850-9-2, an implementation guideline was developed in 2004. This guideline specifies the data sets that are transmitted, sampling rates, time synchronisation requirements and physical interfaces, but does not specify the transient response of devices. The IEC 61869 is a series of standards being developed by IEC TC38 to address this. SV sources throughout a substation must accurately time stamp each sample to allow protection IEDs to use SV data from several sources. 9-2LE specifies an optical 1 pulse per second (1pps) timing signal with ±1 µs accuracy for this purpose.

There is considerable overhead with 9-2LE based sampled values. A standard 802.1Q tagged Ethernet frame (see Figure 1) has twelve bytes of frame wrapping, twelve bytes of address information, four bytes of 802.1Q tag, two bytes of Ethertype and then the payload.

Generic 802.1Q Tagged Ethernet Frame

Preamble	Start Frame Delimiter	Destination Address (3 bytes)	Source Address (3 bytes)	802.1Q Ethertype (8100_{16})	Priority 0-7 (3 bits)	Canonical Format Ind. (1 bit)	VLAN ID (000_{16} to FFE_{16}) (12 bits)	Payload Ethertype	Payload	Frame Check Sequence

Figure 1 – Generic 802.1Q Tagged Ethernet Frame

The SV payload defined in IEC 61850-9-2 and 9-2LE has its own overhead with ASN.1 encoding and other fields that identify the source of the sampled data and a time stamp (see Figure 2).

Sampled Value Protocol Overhead

Ethertype $88BA_{16}$	Application ID (4000_{16})	SV Data Length	Reserved	Protocol Overhead (APDU/ASDU)	*svID* Source Name	*smpCnt* Sample Counter	*confRef* Configuration Revision	*smpSynch* Synch. Sampling	Measurement Data

Figure 2 - Sampled Value Protocol Overhead

IEC 61850-9-2 is a multicast protocol and so specific destination addresses are used. The IEC recommend that destination MAC addresses in the range 01-0C-CD-04-00-00 to 01-0C-CD-04-1F-FF be used for Sampled Values.

The measurement dataset set (see Figure 3) consists of eight 32-bit signed integers (four currents and four voltages) and eight 32-bit status/quality words associated with each of the integer readings, which is based upon the dataset specified in IEC 60044-8. Fixed scaling is used to convert primary quantities to the integers (secondary values are not used). Currents are multiplied by 1000 and voltages by 100. These scaling factors and 32-bit integers give maximum values of approximately 1100 kA_{RMS} and 11000 kV_{RMS}, which should be sufficient for most power system applications, even with harmonic distortion.

Sampled Value Measurement Data

I_A x 1000 (32 bit int.)	I_A Quality (32 bits)	I_B x 1000 (32 bit int.)	I_B Quality (32 bits)	I_C x 1000 (32 bit int.)	I_C Quality (32 bits)	I_N x 1000 (32 bit int.)	I_N Quality (32 bits)	...
...	V_A x 100 (32 bit int.)	V_A Quality (32 bits)	V_B x 100 (32 bit int.)	V_B Quality (32 bits)	V_C x 100 (32 bit int.)	V_C Quality (32 bits)	V_N x 100 (32 bit int.)	V_N Quality (32 bits)

Figure 3 - Sampled Value Measurement Data

The net effect is that a 126 byte Ethernet frame contains 24 bytes of raw data in a three phase system. The other 102 bytes are the price that is paid for quality attributes and interoperability.

The protection mode of 9-2LE requires a SV source to transmit waveform data 80 times per nominal cycle, which is 4000 Hz for a 50 Hz power system. Since each frame of SV data contains one reading, this results in 4000 frames per second being transmitted for each three phase set. Some devices may sample more than one point in the substation, and so will transmit one frame for each set. The maximum number of SV sources supported with 100 Mbps Ethernet is 22 for a 50 Hz system, and this results in 88 000 frames per second being transmitted. The load that switching many small frames places on an Ethernet switch should not be underestimated.

3 Project Scope

The main objective of Powerlink's pilot installation was to trial NCITs communicating across a switched Ethernet network using SV Process Bus according to 9-2LE. This installation would parallel the existing numerical protection system installed on the 275 kV Line Reactor bay at Powerlink Queensland's Braemar substation.

The Braemar substation was part of a series of turnkey projects undertaken by ABB in 1999 when Powerlink introduced an integrated substation design known as iPASS which included NCITs for current and voltage measurement. ABB's NCIT solution for iPASS called CP (combination of CT and PT) is a single-phase unit, designed for use in GIS products. The Line Reactor at Braemar was already equipped with CPs on the line side of the iPASS breaker and conventional CTs in the HV Bushings and Neutral of the Line Reactor, providing an ideal test bed for the trial.

The pilot installation had to meet the following objectives:

- Test the protection system performance of the FOCT with 9-2LE interface from SDO
- Test 9-2LE interoperability of FOCT and CP using a Transformer protection IED with 9-2LE interface
- Test the mixed application of conventional CTs and NCITs for the purposes of Transformer Protection
- Allow Powerlink staff to gain engineering and field experience with FOCT technology and SV Process Bus

The pilot installation had to be decoupled from the existing 'in-service' equipment to ensure testing performed on the pilot system would not have any adverse impact on the existing protection systems. Both protection systems – the in-service system as well as the pilot system had to be designed to allow a comparison of current/voltage waveforms and event records should either of the protection systems detect a fault condition on the HV network.

The following sections will provide more details on the FOCT from SDO, the primary plant layout and the protection system configuration. The NCIT solution from ABB is illustrated in [15] and will not be discussed any further in this paper.

3.1 Optical Fibre Current Sensor from Smart Digital Optics

The SDO SA1T is a Faraday Effect optical fibre current sensor. The sensing head contains a coil of sensing fibre arranged so that the primary current passes through the sensing coil. This current creates a relative phase shift between two counter-propagating optical signals in the coil. The phase difference is measured by interfering the counter-propagating signals in an optical coupler.

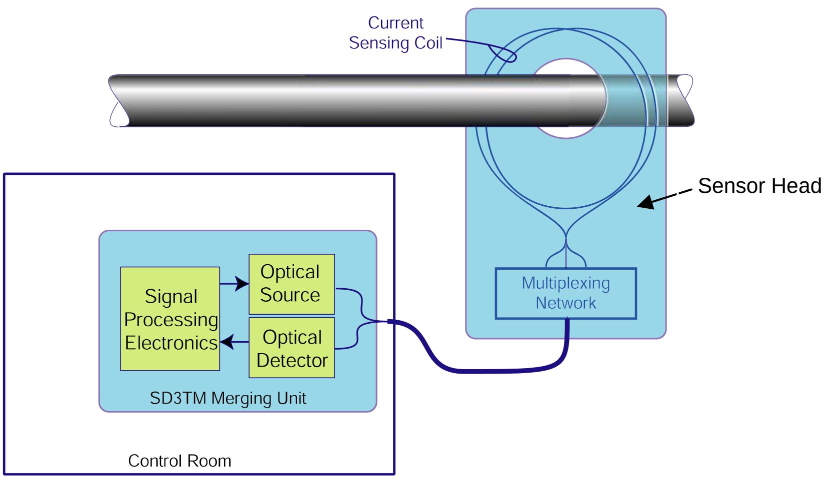

Figure 4 - Diagram of SA1T Current Sensor System

The SA1T system incorporates an advanced signal processing technique, called NIMI, which combines a passive optical multiplexing network and a signal processing algorithm to eliminate sensitivity to environmental effects (vibration, temperature and losses) in the sensor and interconnecting network.

The SD3TM is a combined optical current sensor interface and Merging Unit (MU). This unit is designed to be rack mounted in the switchyard control room and provides an optical interface to three SA1T current sensors and an output conforming to 9-2LE. The SD3TM uses a 1pps optical signal for synchronisation with other SV Process Bus devices. The connection between the sensor heads and MU is made using a duplex single mode optical fibre cable. In addition to the 9-2LE interface, the SD3TM provides an electrical Ethernet connection for system configuration and diagnostics. This user interface communicates to a web server in the MU and requires only a standard web browser to operate. All system parameters can be configured through these web pages. System diagnostics (alarm status, optical signal levels, etc) can also be viewed.

3.2 Primary Plant Layout

Figure 5 shows a plant cross-section of the 275 kV Line Reactor bay at Braemar substation. The FOCT was added to an existing post insulator. A polymer insulator was installed between the FOCT sensor head and the base of the existing Surge Diverter (SD) support structure. The insulator houses the single mode fibre that connects the primary part of the sensor to the sensor electronics that reside in the demountable control building.

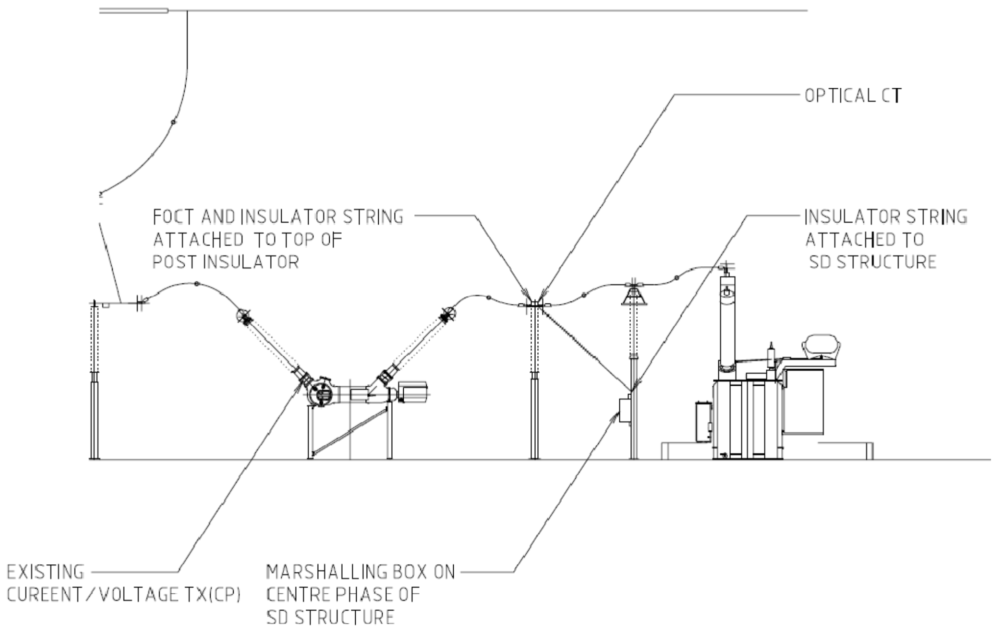

Figure 5 - Primary Plant Layout

The optical fibres from the three 1-phase units are marshalled in a fibre optic patch box, located at the bottom of the SD support structure and run to the control building in a conventional underground single mode fibre optic cable. A Corona ring is installed on top of the polymer insulator to prevent damage on the insulator caused by partial discharge.

3.3 Substation Automation System Architecture

A new control and protection cubicle was designed to house all the secondary equipment needed for the pilot installation and to ensure that modifications to the in-service ABB protection systems could be kept at a minimum. It also has provisioning to expand the pilot in the future as and when required. The protection trip signals of the pilot system have not been wired to the primary plant.

Figure 6 shows the configuration of the protection system. The CP and FOCT are connected to the Protection IED via their corresponding MUs with 9-2LE interfaces. The differential element of the Transformer Protection IED is working with current inputs from the CP on the line side and the CT in the Reactor Neutral. The Protection IED can easily be reconfigured to work with the current inputs from the FOCT or the conventional CT of the Line Reactor HV bushing. All current signals are mapped into the disturbance recorder log of the IED to allow a meaningful comparison of all waveforms including currents from CP, FOCT, HV Bushing CT and CT in Reactor Neutral as well as voltages from Bus VT and CP. The in-service protection system and the pilot system have been engineered to cross-trigger the disturbance recorders. This allows a comparison of data recorded in both systems for detection of an event in either of the two systems. The Protection IED used in the test system only supports SV Process Bus on one physical Ethernet port, with an Ethernet switch used for the merging of the two independent SV data streams.

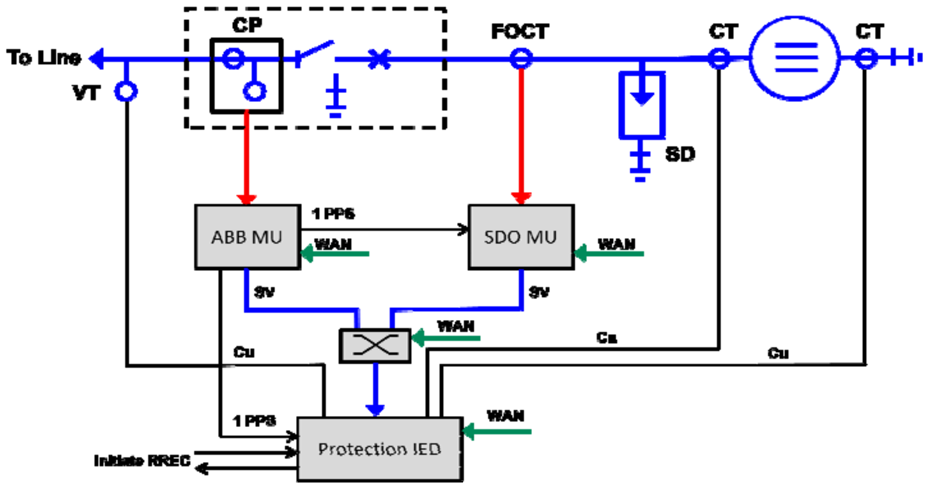

Figure 6 - Substation Automation System

All devices including MUs, Protection IED and Ethernet switches have been configured to enable remote diagnostics and configuration changes via an Engineering Workstation located on site. Access can be gained via a WAN used for operational purposes (OpsWAN). Mirror ports on the Ethernet switch allow packet captures on the SV Process Bus for monitoring and analysis.

4 IEC 61850 Interoperability Tests Results

9-2LE specifies the information that is required in a SV frame, however there is still flexibility in the way that manufacturers can implement the protocol. Packet captures of SV streams were collected using Wireshark. The PCAP files created by Wireshark were analysed using the tools built into the Wireshark and other tools. SV data captured from MUs, protection test sets and real time simulators were analysed against the following criteria: correct IEC 61850-9-2 formatting/encoding, implementation of the UCAi 9-2LE guideline and use of ASN.1 BER encoding options.

4.1 Encoding Errors

Length errors were observed in the header part of the SV frame (before the APDU) and within the ASN.1 encoded data for some SV sources. These errors break compliance with

IEC 61850-9-2, and shows that protocol compliance testing is required before devices are deployed into the field.

9-2LE uses the final two characters of the MU name (svID) to indicate which APDU is used. Protection/metering frames are sent 4000 times per second for a 50 Hz power system (80 frames per cycle with a single sample of each phase) and should have an svID ending in ‘01’. Power quality frames are sent 1600 times per second for a 50 Hz power system (32 frames per nominal cycle, with eight samples of each phase) and the svID should end in ‘02’. One manufacturer placed the fixed `01' in the wrong position of the svID (third and fourth from the end, instead of first and second from the end), and so subscribing IEDs would be unable to determine the specific content of the SV data and would discard the data.

Ethernet requires padding bytes when the frame size is less than 64 bytes long (to ensure sufficient transmission length for collision avoidance using CSMA/CD on unswitched networks). Figure A.1 of IEC 61850-9-2 mentions this, but one of the SV data sources misread this to allow padding after the APSU. Two extra bytes were added as this simplified their implementation. A standard 9-2LE frame is more than 64 bytes long and so no padding is necessary. Extra data that is not allowed for in the length variables may corrupt the decoding of SV data by IEDs and lead to maloperation.

4.2 Visualising Data

An Engineering Workstation at the substation was connected to the Process Bus switch (through a mirror port) to enable remote capture of SV data. Through remote access to the capture computer, it was possible to initiate a Wireshark capture and then transfer the PCAP file back for analysis. This gives access to the raw data, as well as waveform capture on protection IEDs to examine line currents and voltages.

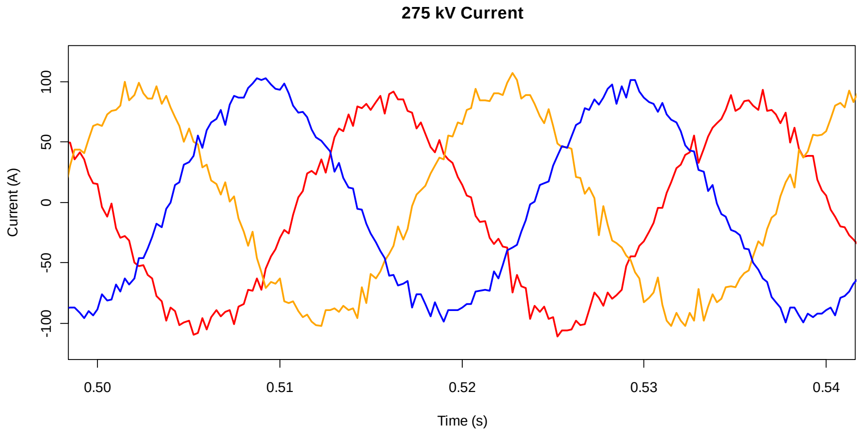

Figure 7 - Sampled Value data stream remotely extracted using Wireshark

A script was written for Wireshark that extracted current and voltage waveforms from saved PCAP files. Commercial software is also available to analyse live or pre-recorded SV streams. The waveforms in Figure 7 were recovered from a remote Wireshark capture. The noise on the signal is due to the low current level, as the FOCT used is capable of measuring currents up to the fusing current of its internal busbar. The noise would/will decrease when the primary current level is increased, improving the signal to noise ratio of the measuring system.

4.3 IEC 61850 Quality Attributes

Data quality is part of the SV data packet and is defined in IEC 61850-7-3 [13]. Edition 1 of the IEC 61850 standard does not clearly specify how the different quality attributes have to be implemented and supported within the devices. The interoperability issues observed during the 9-2LE testing between FOCT and Protection IED included implementation of the quality attributes ‘validity’ and ‘test’. Edition 2 of the IEC 61850-7-3 standard addresses this issue with a view to improve the consistency of the implementation of quality attributes.

5 Comparison of Testing Methodology

Testing should consider all aspects of the design. Independent of whether conventional ITs or NCITs are being tested, the first action undertaken by the testing team is to ensure that the equipment is installed correctly in the HV substation. This consists of confirming that the orientation of the equipment is correct in relation to the other HV plant and a visual check for any damage from either transport or installation. In this aspect, there is no difference between the requirements of a conventional CT and that of the SDO FOCT or any other NCIT.

Conventional CTs at transmission level voltages utilise either oil or SF_6 as an insulating medium. In the case of oil filled CTs, the oil level is checked following an oil sample and is either checked onsite or sent to the laboratory for analysis. In the case of SF_6 filled CTs, the dew point is measured and the pressure is confirmed to be correct in accordance with the rating plate and/or manual. For NCITs that utilise SF_6 the process is the same as for a SF_6 filled conventional CT. Due to the construction/design of the SDO FOCT there is no requirement for oil or SF_6 insulation and as such this aspect of testing is not required.

Majority of the tests conducted on conventional CTs are due to their design/construction and resulting electro-magnetic properties. A standard test conducted on conventional CT is the Insulation Resistance (IR) Test. The testing of each of the windings - HV - Earth, HV – Secondary, Secondary – Earth is commonly performed with a 5 kV Insulation test set. magnetising curves, DC winding resistance, polarity and ratio tests are also undertaken on each core (and tap for multi-tapped cores) of a conventional CT using conventional test methods and equipment. The order of the above tests are important to ensure that the results obtained are correct and that the CT is ready for service when complete, therefore avoiding any issues such as remnant or residual flux of the core of the CT which may cause distortion of the measured signal during the initial period of operation. The conventional CT is checked by circuitry wiring point to point and the DLA link shorted as required. All secondary cores are checked for continuity and a measurement of the secondary loop resistance is taken. All used secondary cores are checked for a single earth whilst unused cores are shorted and earthed to prevent any generation of high open circuit voltage or capacitive voltage rise.

In relation to the FOCT from SDO, due to their design/measurement principle and construction, many of the tests performed on a conventional CT are not required or not applicable. Of those that are, many require a different test method or equipment. The IR test performed on the SDO FOCT is similar to a conventional CT with only the HV-Earth portion of the test performed - this is due to the fibre optic secondary connection. A magnetising curve and DC winding resistance measurement is not applicable to the FOCTs.

The SDO MU is integral to the operation of the FOCT, therefore any further tests can be undertaken; the connection (fibre optic link) between the MU and the sensor head needs to be established. This process is in many ways analogise to that of secondary wiring point to point, loop resistance measurements and test for single secondary earth on a conventional CT. There are two fibre optic cores connecting each SDO FOCT sensor head and MU. Once installed, all fibre optic terminations need to be inspected with a microscope and optical camera to confirm that they are correctly terminated, polished and free of any cracks, contaminants, inclusions or dirt which may increase their attenuation of the fibre optic signal. Individual dB loss levels and measurements are performed and recorded using a standard single mode optical source and level meter. These results are recorded and form part of the overall test documentation and record. It is also critical that for each phase, the Channel A on the MU connects to the Channel A on the SDO sensor head, and similarly for Channel B. With these initial checks and the MU powered on, it is possible for the MU to perform internal diagnostics of the optical signal strength and confirm that the system is operating correctly. The output of the MU is set to a predefined output level to accommodate large distances or lossy connections between the MU and the sensor head. In cases where the distance is short, or the losses are low, it may be necessary to apply an external fibre optic attenuator between the MU and the sensor head where the signal is being overdriven.

A similar style of polarity test to that of a conventional CT can be undertaken with differences to the method of the measurement. In particular, consideration needs to be given to the type of output provided from the SDO FOCT. In the case of the SDO FOCT using a MU with output 9-2LE, the output is compared with that produced directly from the test set to a signal monitoring device for analysis and comparison. Note: Consideration of the signal used for the test is required. To reduce issues such as synchronisation/timing delay through the MU etc., the signal used for the test is either a DC pulse of short duration, or a small number of power frequency cycles. This reduces the sophistication of the signal monitoring device as the length of the DC pulse or total number of cycles used for the injection provides the correlation for comparison.

In addition to the standard tests solely performed on the CT, there are the additional tests to integrate it with the protection scheme/system. These typically include primary injection for in zone and out of zone faults, check and confirmation that CTs summate as required by the design. Typically these tests would use an injection test set capable of producing in the order of 50-1000 A through the CT and/or primary equipment. In these tests, there is little or no difference in the method between a conventional CT and that of the SDO FOCT.

6 Test Results and Service Experience

As the measurement principle employed in the SDO is different to that of a conventional CT, its performance under transient conditions as well as steady state were of interest. A test setup for the comparison of the SDO FOCT and a conventional CT was developed and is shown in Figure 8.

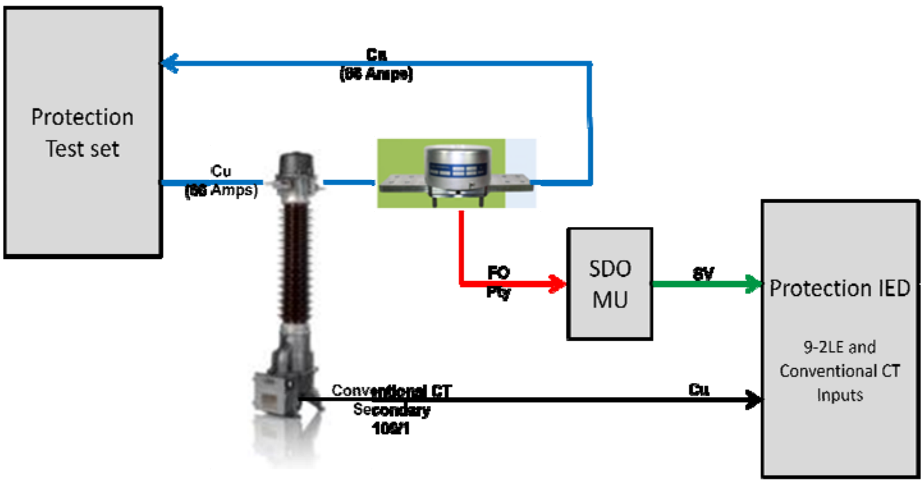

Figure 8 – Protection Test Setup

The first test performed was injecting a steady state sinusoidal current of 66 A at the power system frequency (50 Hz). Figure 9 shows the monitoring device's capture of the output for this test. The captured waveform is in phase and of correct magnitude.

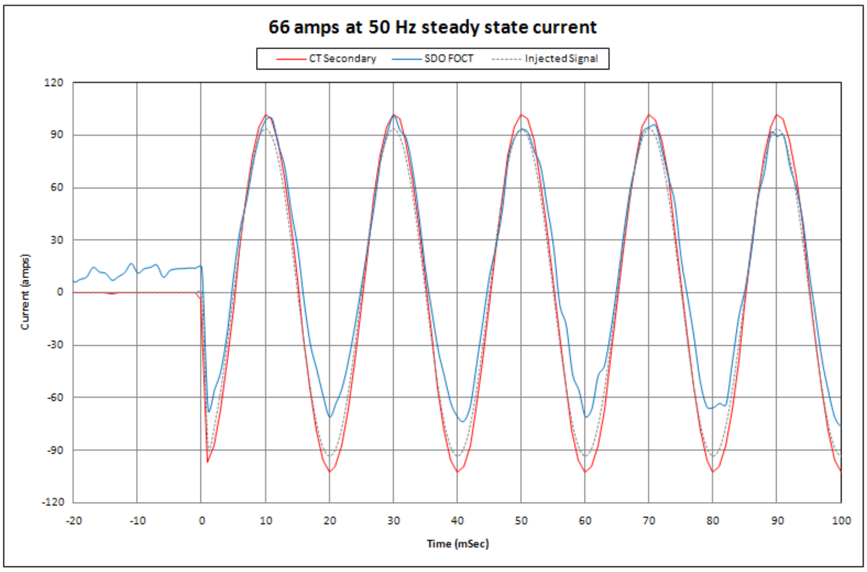

Figure 9 - Stability Test

On closer inspection, although the waveform appears to be that of the injected signal, it is apparent that there is a small level of noise superimposed on the measured signal. This is due to the relatively small injected test current (66 A DC), in comparison to the SDO FOCT rated nominal current (2500 A). With higher injected current levels, the relative noise reduced accordingly. This is also the explanation for the small DC offset that may be seen in the captured waveform.

The next test involved the injection of a DC Pulse through both the conventional CT and that of the SDO FOCT. The captured waveform from this test is shown in Figure 10.

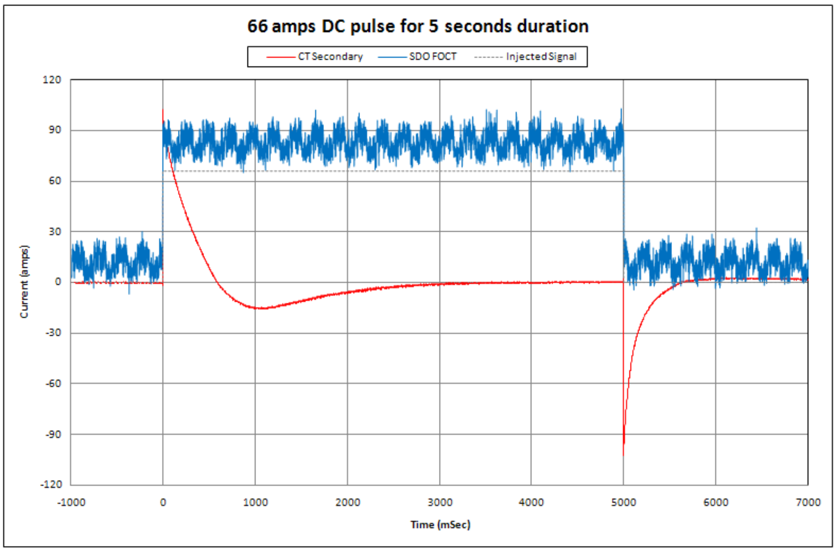

Figure 10 - DC Pulse

As was the case for the steady state test the SDO FOCT shows a small amount of noise and DC offset superimposed on the output signal. The conventional CT performed as was expected based on the electromagnetic principles of its design, however the SDO FOCT provided a true representation of the injected signal in both magnitude and phase. This reflects the theoretical performance of bandwidth and dynamic range associated in general with NCITs.

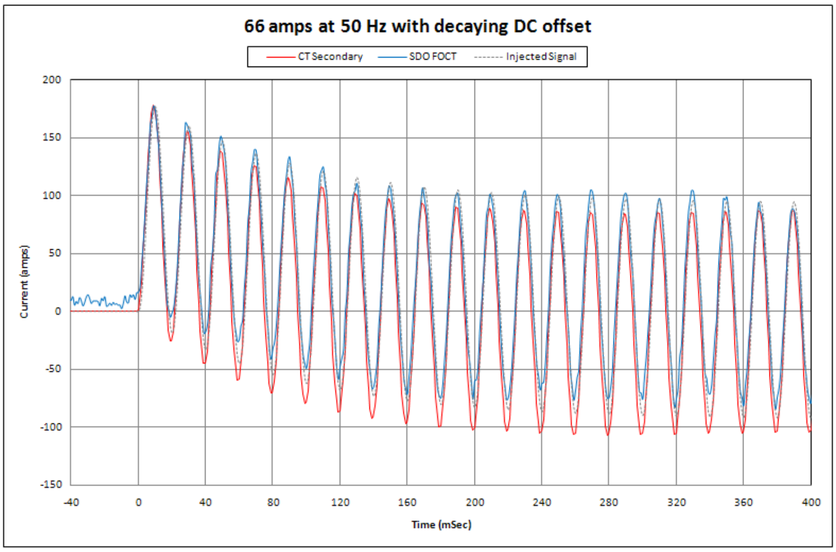

Figure 11 - Decaying DC

The final test of interest was the behaviour of the SDO FOCT with that of the conventional CT for the simulated power system fault. The simulated fault consisted of an AC waveform superimposed on an exponentially decaying DC offset. Due to limitations in the test equipment, the test current was run at the same level (66 A) as that of the steady state and DC Pulse tests. Figure 11 shows the resulting captured waveform for this test.

The captured waveform shows that there is a difference again between the performance of the conventional CT and that of the SDO FOCT. The SDO FOCT was an exact replication of the injected signal. However the conventional CT shows a different response in terms of the decay or L/R of the injected signal.

The results of the testing performed for the above scenarios are evidence of the differing transient behaviour between that of a conventional CT and NCITs, in this case the SDO FOCT. This should be seen as a basis for the need to develop and release a standard that covers the performance of NCITs.

Additional consideration is that of the IED vendor and how the IED should perform or interpret the difference in performance for that of a conventional CT with that of an NCIT or differing NCITs.

7 Performance during twelve months of service

The Pilot has been installed and operating for twelve months without any issues thus far. During this time the Pilot has provided design and field staff with exposure to the different skills associated with this new type of NCIT, specifically the handling and cleanliness of Fibre Optics, safety requirements, test methodology and other related work practices. Due to a 275 kV Line Reactor's surge diverter operating (during an auto reclose operation on the transmission line) clamping the voltage on the A Phase to ground, the SDO NCIT was subjected to a fault current of 36 kA. The resulting measured waveform obtained from this fault condition is shown in Figure 12. Due to the location of the fault, between the SDO FOCT and that of the Reactor's conventional CTs, the waveform was only available to that of the SDO FOCT. The waveforms from the local and remote ends of the transmission line provided good correlation with the SDO FOCT waveform. The waveform also shows a decaying DC offset prior to the circuit breakers operating to clear the fault.

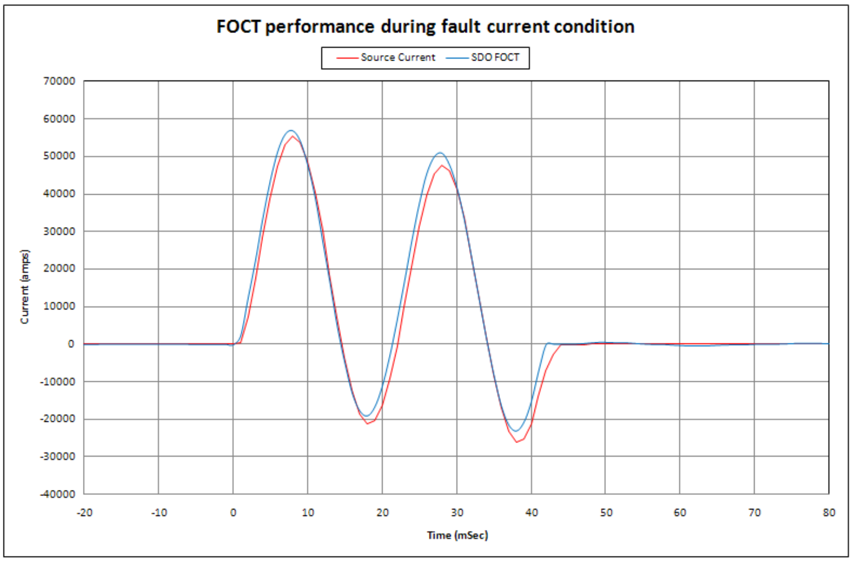

Figure 12 – FOCT Fault Response

8 Work Practice and Safety Considerations

Over the last ten to fifteen years fibre optic communications have been increasing within the substation environment. Initially fibre optic connections were single mode and associated with substation to substation communications. They were installed and maintained by dedicated personnel with communications backgrounds, with knowledge and appreciation to the specific safety issues. In more recent times, multimode connections between many SAS components have been introduced. This has begun to introduce more personnel to fibre optic communications and their requirements for handling and use. Although being aware of the potential safety issues, multimode connections due to their lower power (Class) have been adequately covered. With the implementation of devices such as the SDO FOCT, the awareness and handling techniques become more significant. The FOCT has the potential to bring the higher powered laser devices into direct contact with personnel who may not have the understanding or awareness. Prior to the introduction of this type of equipment, it will require consideration to the personnel who may come into contact with such equipment, the signage required, how to isolate the laser source and care of fibre handling. In many cases the previous methods for handling substation to substation communications can be extended to include the general equipment installed within the switchyard.

In addition to impacts of the safe handling and work practices for fibre optic equipment, changes to individual personnel skills and tools are required due to the implementation of FOCTs. The standard tool kit of multimeter, IR meter and basic hand tools for wiring and terminating cabling need expansion to include specialist fibre optic termination kits, fibre optic source and level meters, fibre optic microscope and/or camera for the measurement and inspection of terminations and specialised cleaning kits for fibre optic termination. This equipment is effectively the same type and contents of a communications technician.

9 Future outlook

There is an expectation that NCITs will be more reliable during their service-life compared to conventional ITs. NCITs typically consist of the primary sensor, some electronics and digital communication paths. Some of those elements will require duplication to achieve improved reliability. Multiple options have been considered for the design of the FOCT from SDO including: -

- Duplicate sensor heads
- Single sensor head with duplicate optics
- Single sensor head and optics, interrogated by duplicate optical cables and electronics.

The choice of which level of redundancy has to be implemented will be determined by the utilities requirements and National Electricity Rules. There may also be a need for separate measuring circuits for protection and revenue metering.

Many utilities would want to use NCITs in conjunction with conventional CTs and VTs in their SAS. Using inputs from NCITs and conventional instrument transformers within the same function (i.e. current differential protection) is referred to as “Mixed Mode” application. The input signals have to be timely correlated as the signals might have been sampled with different time sources and at different sampling rates. Some IED manufacturers have implemented Mixed Mode within the protection and control IEDs while others are performing this function within their MU device. Mixing the two concepts in a single SAS is possible but poses some interoperability challenges.

The 9-LE guideline specifies the SV data sets that are transmitted, sampling rates, time synchronisation requirements and physical interfaces, but does not specify the transient response of devices. The IEC 61869 series of standards are being developed to address this issue. MUs throughout a substation must accurately time stamp each sample to allow protection IEDs to use SV data from several MUs (through the use of time alignment of samples in buffer memory).

Outdoor transmission-level substations (typically 110 kV and above) cover a large area of land and cable lengths are significant. IRIG-B can be distributed over copper or fibre optic cables, but rarely has the accuracy required for SV synchronisation. 1pps distributed over fibre optic is required by the 9-2LE guideline, but this does not contain absolute time information which will be required by the data security techniques proposed in IEC TS 62351-6 to prevent ‘replay’ attacks. 1pps systems do not automatically compensate for propagation delay, and if this delay exceeds 2 µs the SV source must compensate for this. Cable lengths in several Brisbane substations exceed 400 m, and so the propagation delay in glass fibre would exceed the 2 µs limit.

IEEE Std 1588-2008, version 2 of the Precision Time Protocol (PTPv2) [17], is recommended in the IEC Smart Grid Roadmap and the NIST Framework and Roadmap for Smart Grid Interoperability Standards as a method of high accuracy time synchronisation. The same data infrastructure can then be used for SV and for time synchronisation. This is of great benefit when MUs are located throughout a substation (adjacent to the primary plant they are connected to), instead of being located in substation control rooms (as done by many suppliers of NCITs including SDO). If 1pps was used, distributed MUs would require a separate fibre optic network throughout the substation just for 1pps, and this would be avoided if PTPv2 was used for synchronisation. Native support of PTPv2 is desirable as most of the extra data available with PTPv2 is lost with 1pps, including accuracy information, absolute time and date (which could be incorporated into SV or synchrophasor messages) and details of the clock source. A 110 kV substation in Dalv, China was commissioned in early 2009 [17] that uses an IEC 61850-9-2 Process Bus for HV process connections and IEEE Std 1588-2008 for synchronising of samples. This substation used protection IEDs from three manufacturers, and was the first time that PTPv2 support was incorporated into IEDs rather than using a PTPv2 slave clock to generate a local 1pps signal.

10 Conclusion

The pilot installation has been in service for over twelve months. Its operation has been stable throughout this time including a power system event, where it was subjected to one high level fault of 36 kA. Invaluable experience has been obtained by design, maintenance and operations personnel during this time.

Some technical challenges still remain for NCIT suppliers and vendors of protection, control and metering equipment before large scale deployment can occur. Solutions for mixed applications of NCITs and conventional ITs must be developed. Also IEC TC38’s work to develop and release a new standard to address the transient performance of NCIT solutions including MUs is key to achieve true interoperability in multivendor systems. It is expected that NCITs will be more reliable than conventional ITs and that the same device can be used for protection, instrumentation, revenue metering and power quality measurement applications.

The standards and equipment for NCIT technology and MUs should rapidly mature over the coming years. This will allow power utilities to build safer and better performing substation assets at lower cost by implementing the full benefits of the new technology developments and IEC 61850 Process Bus.

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Biography

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